

22 July 2024

Trading conduct report 14-20 July 2024

Market monitoring weekly report

Trading conduct report

1. Overview

- 1.1. Low wind generation, very high gas prices and falling storage contributed to high spot prices this week, with prices at both Benmore and Ōtāhuhu frequently above the 90th percentile. HVDC Pole outages took place on Saturday and HVDC round power¹ was disabled on Friday, contributing to high South Island spot prices and sustained instantaneous reserve price separation. TCC, Huntly 5 and three Rankines provided baseload generation this week. National controlled hydro storage decreased to around 63% of historical average.

2. Spot prices

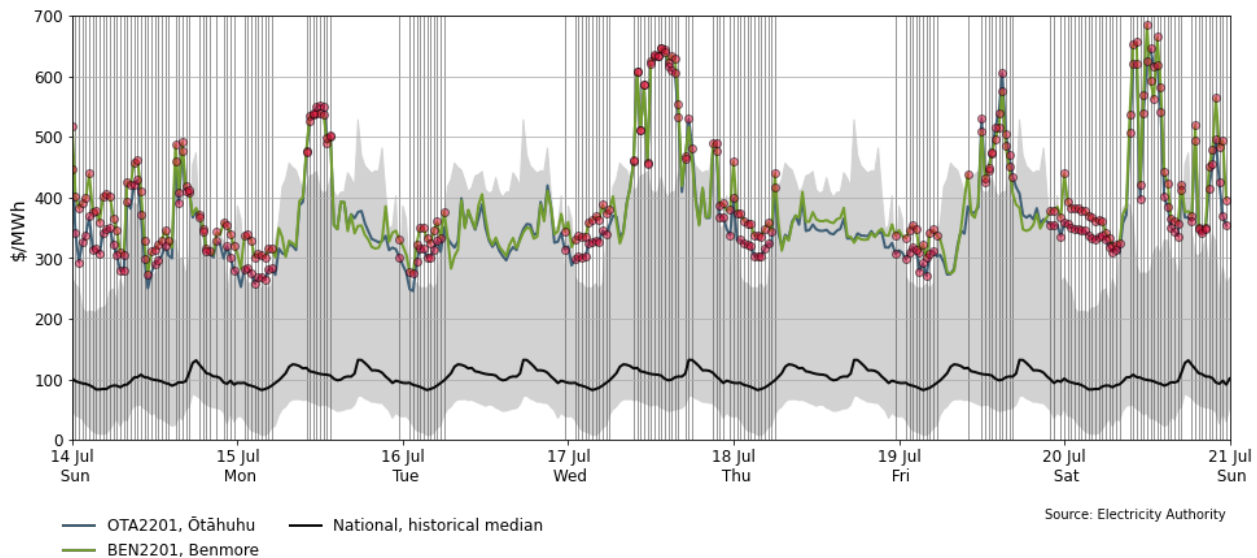
- 2.1. This report monitors underlying wholesale price drivers to assess whether any trading periods require further analysis to identify potential non-compliance with the trading conduct rule. In addition to general monitoring, it also singles out unusually high-priced individual trading periods for further analysis by identifying when wholesale electricity spot prices are outliers compared to historic prices for the same time of year.
- 2.2. Figure 1 shows the wholesale spot prices at Benmore and Ōtāhuhu alongside the national historic median and historic 10-90th percentiles adjusted for inflation. Prices greater than the national historical 90th percentile are highlighted with a vertical black line. Other notable prices are marked with black dashed lines.
- 2.3. Between 14-20 July:
 - (a) the average wholesale spot price across all nodes was \$380/MWh.
 - (b) 95% of prices fell between \$272/MWh and \$628/MWh.
- 2.4. Overall, the majority of spot prices were within \$323/MWh and \$406/MWh, with the weekly average price increasing by \$45/MWh compared to the previous week. Prices at Benmore were generally higher than at Ōtāhuhu, with the average Benmore price \$17/MWh higher than the average Ōtāhuhu price.
- 2.5. Prices were often above the 90th percentile this week. These consistent high prices are primarily the result of low hydro storage and thermal generation costs rising due to uncertain gas supply; the average price this week was similar to the marginal cost of gas fuelled thermal plants. Most of the highlighted prices occurred on weekends or outside of peak demand periods.
- 2.6. Demand forecasting inaccuracies likely contributed to this week's high prices. Demand was more than 100MW higher than forecast at times highlighted prices occurred on Sunday, Monday, Wednesday, Friday and Saturday.
- 2.7. Periods of low and over forecast wind generation were also a factor in the high prices seen this week. From Tuesday onwards, wind generation was mostly below 200MW. Additionally,

¹ Round power allows flow across the HVDC to change direction without first dropping to zero. More information is available from: <https://www.transpower.co.nz/system-operator/information-industry/operational-information-system/frequency-keeping-control-and>

it was more than 100MW below forecast at times high prices occurred on Sunday, Tuesday and Saturday.

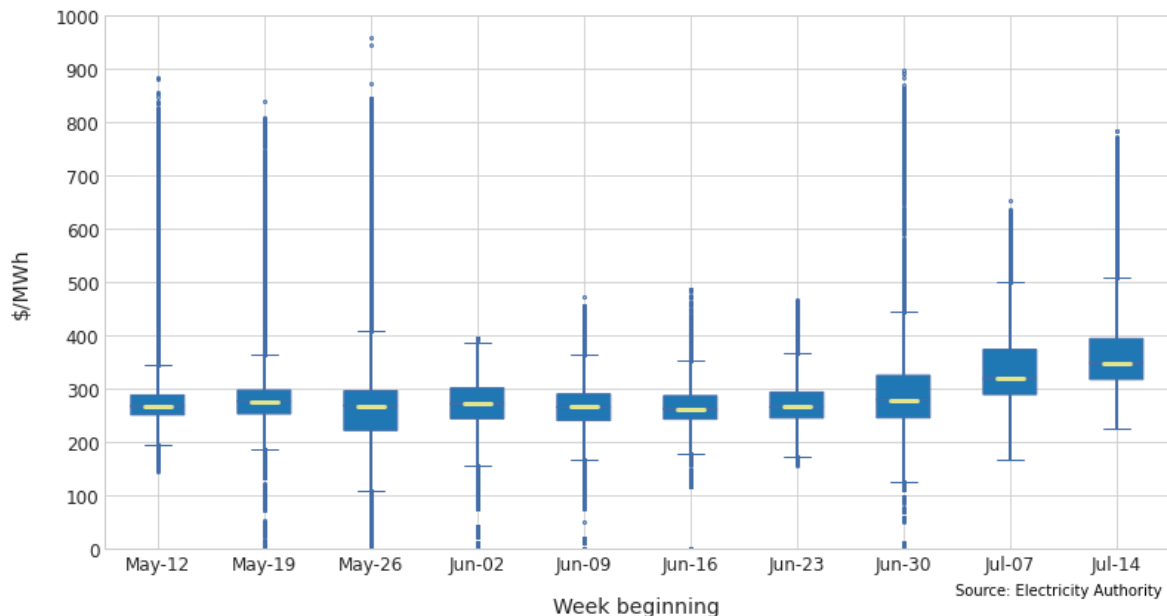
- 2.8. Prices were above the 90th percentile for most of Saturday, with the Benmore price reaching a maximum of \$686/MWh at 12:00pm. Demand was 152MW higher than forecast at this time, while wind generation was both over forecast and low at 80MW. HVDC Pole 3 was on outage at the time, limiting southward transfer and contributing to the Benmore price being \$60/MWh higher than at Ōtāhuhu.

Figure 1: Wholesale spot prices at Benmore and Ōtāhuhu, 14-20 July



- 2.9. Figure 2 shows a box plot with the distribution of spot prices during this week and the previous nine weeks. The yellow line shows each week's median price, while the blue box shows the lower and upper quartiles (where 50% of prices fell). The 'whiskers' extend to points that lie within 1.5 times of the interquartile range (IQR) of the lower and upper quartile. Observations that fall outside this range are displayed independently.
- 2.10. Compared to the previous week, the median price increased by \$36/MWh. The spread of prices has shifted up, with 75% of this week's prices sitting above the median from the previous week.

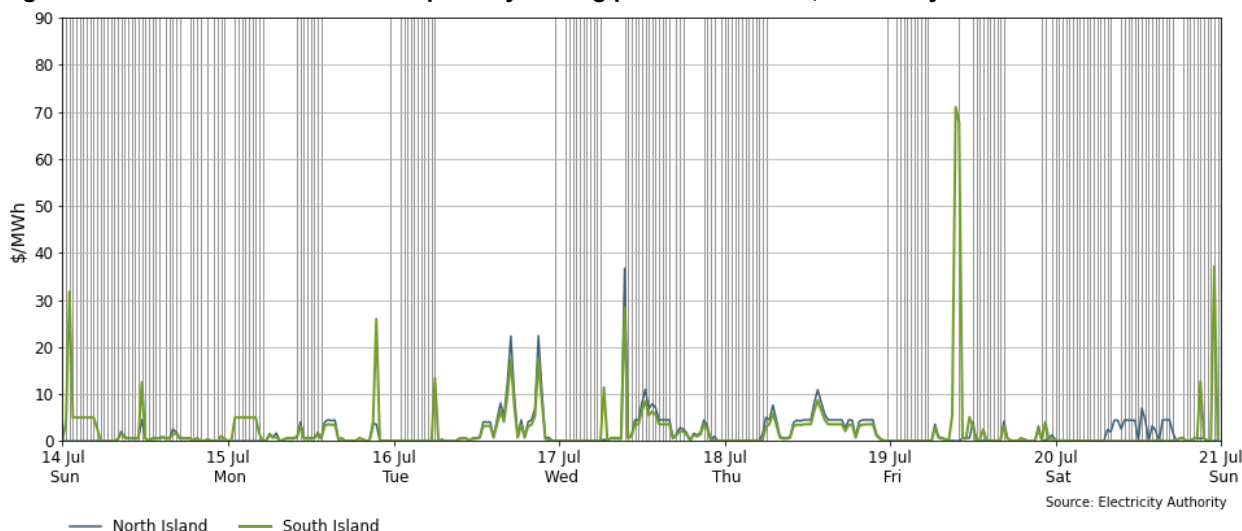
Figure 2: Box plot showing the distribution of spot prices this week and the previous nine weeks



3. Reserve prices

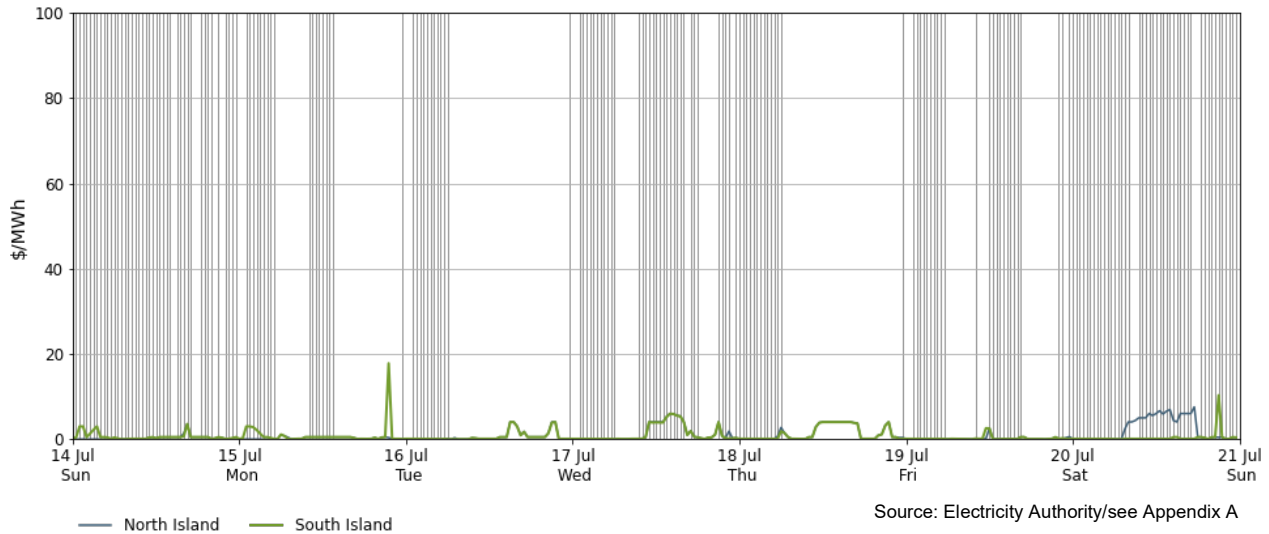
- 3.1. Fast instantaneous reserve (FIR) prices for the North and South Islands are shown below in Figure 3. FIR Prices were generally below \$1/MWh, but spiked on at 10:00am on Friday, reaching \$68/MWh in the South Island while remaining at \$0.02/MWh in the North Island. HVDC round power was disabled at the time, preventing reserve sharing between islands and causing prices to separate.

Figure 3: Fast instantaneous reserve price by trading period and island, 14-20 July 2024



- 3.2. Sustained instantaneous reserve (SIR) prices for the North and South Islands are shown in Figure 4. SIR prices were generally below \$1/MWh this week, reaching at maximum of \$18/MWh in the South Island at 9:30pm on Friday.

Figure 4: Sustained instantaneous reserve by trading period and island, 14-20 July 2024

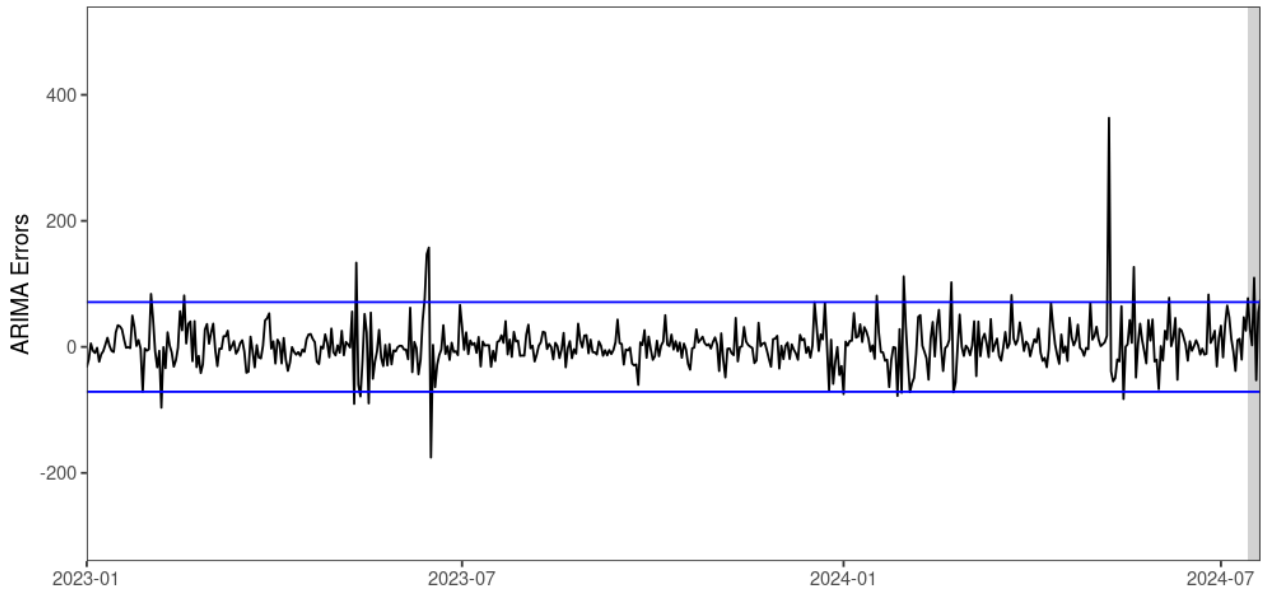


Source: Electricity Authority/see Appendix A

4. Regression residuals

- 4.1. The Authority's monitoring team uses a regression model to model electricity spot prices. The residuals show how close predicted spot prices were to actual prices. Large residuals may indicate that prices do not reflect underlying supply and demand conditions. Details on the regression model and residuals can be found in [Appendix A](#).
- 4.2. Figure 5 shows the residuals of autoregressive moving average (ARMA) errors from the daily model. Positive residuals indicate that the modelled daily price is lower than the actual average daily price and vice versa. When residuals are small this indicates that average daily prices are likely largely aligned with market conditions. These small deviations reflect market variations that may not be controlled in the regression analysis.
- 4.3. This week, the residuals for Sunday, Wednesday and Saturday were above two standard deviations of the data, indicating that prices on these days were higher than the model expected. This is likely due to demand being significantly higher than forecast on these days, with forecast errors not factored into the ARMA model. Our analysis shown in figure 12 indicates that had demand been closer to forecast, prices would not have been as high.

Figure 5: Residual plot of estimated daily average spit prices, 1 January 2023 – 6 July 2024

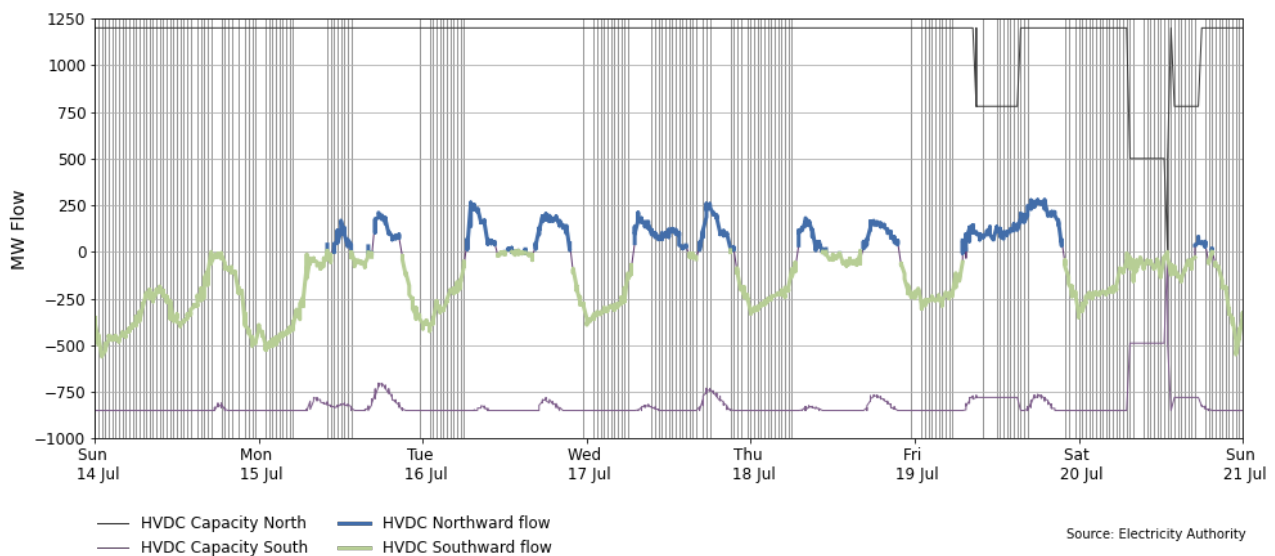


Source: Electricity Authority/see Appendix A

5. HVDC

- 5.1. Figure 6 shows the HVDC flow between 14-20 July 2024. HVDC flow was entirely southward on Sunday, when North Island wind generation was relatively high and prices were mostly above the 90th percentile. Flow was also southward at the times most of the other highlighted prices occurred.
- 5.2. On Saturday, HVDC Pole 3 was on planned outage from 7:30am to 1:30pm and HVDC Pole 2 was on outage from 2:00pm to 6:00pm. HVDC round power was also disabled from 9:00am to 4:00pm on Friday. This constrained reserve sharing and lead to FIR prices separating and spiking in the South Island.

Figure 6: HVDC flow and capacity, 14-20 July 2024

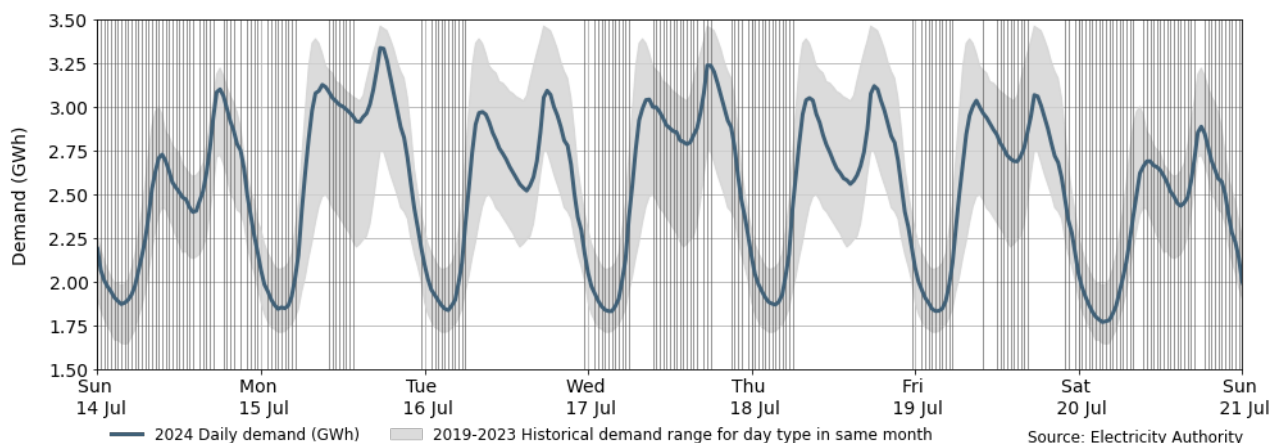


Source: Electricity Authority

6. Demand

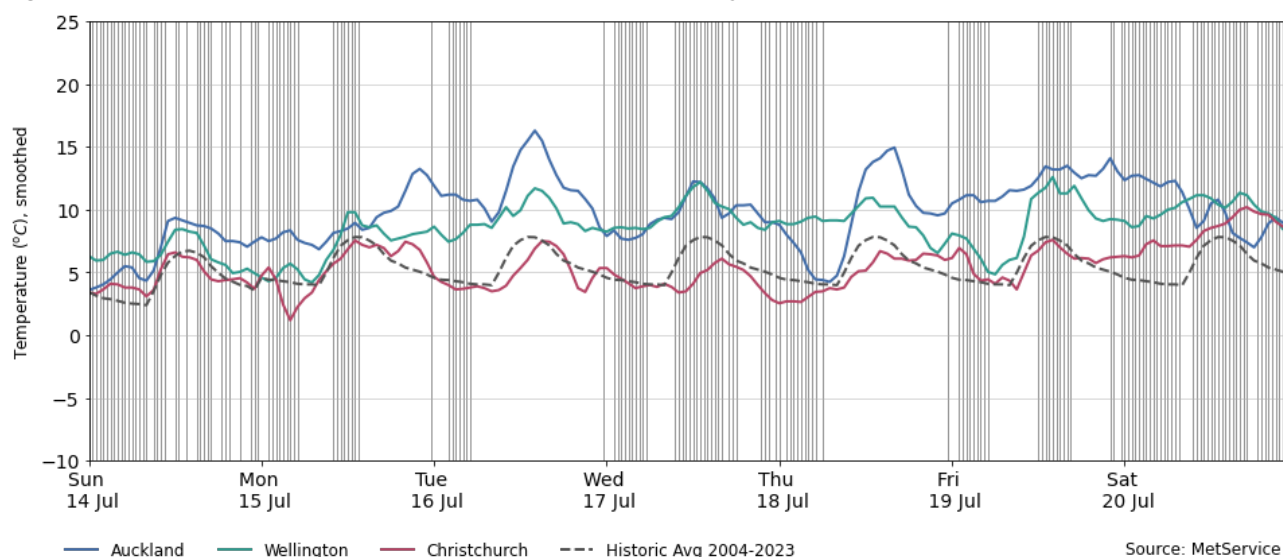
- 6.1. Figure 7 shows national demand between 14-20 July 2024, compared to the historic range. Demand was within the historical range for July. Maximum demand for the week was 3.34GWh at 5:30pm Monday.

Figure 7: National demand, 14-20 July 2024 compared to historic range



- 6.2. Figure 8 shows the apparent temperature at main population centres from 14-20 July 2024. The apparent temperature adjusts the measured temperature for factors like wind speed and humidity to estimate how cold it feels. Also included for reference is the mean historical temperature for the same in July from previous years, averaged across the three main population centres.
- 6.3. Temperatures were mostly above average this week, ranging from 4°C to 16°C in Auckland, 4°C to 13°C in Wellington, and 1°C to 10°C in Christchurch.

Figure 8: Apparent temperatures across main centres, 14-20 July 2024

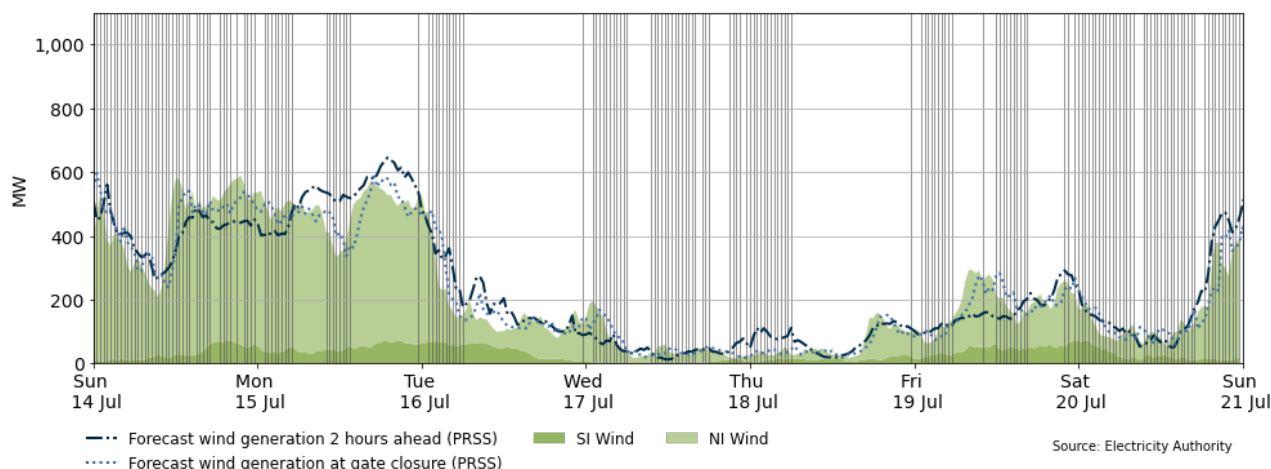


7. Generation

- 7.1. Figure 9 shows wind generation and forecast from 14-20 July 2024. This week wind generation varied between 17MW and 591MW, with a weekly average of 221MW. Wind generation was low this week, mostly below 200MW from Tuesday onwards.

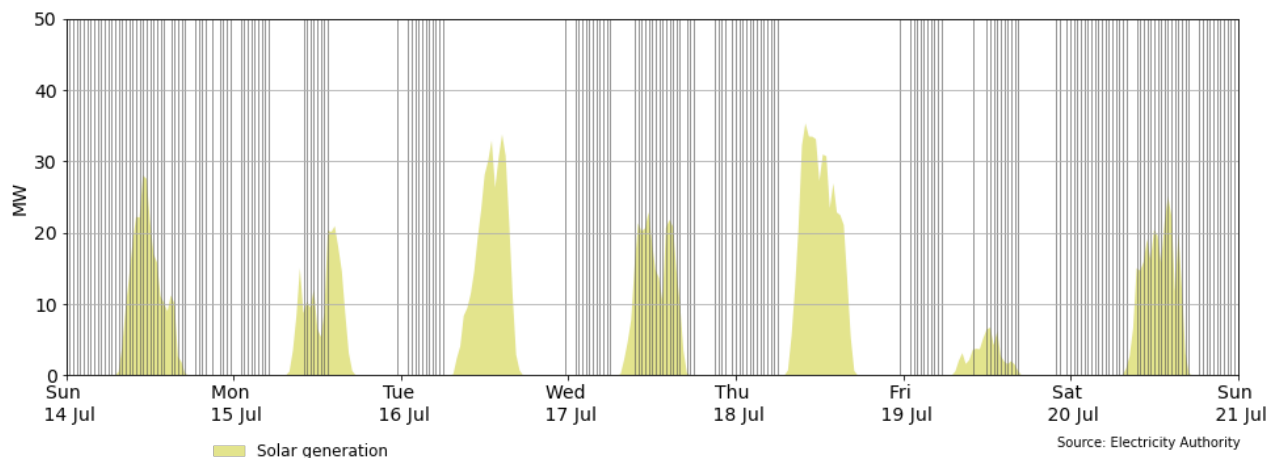
- 7.2. Forecasting inaccuracies likely contributed to high prices between Sunday and Tuesday and on Saturday, with generation more than 150MW below forecast when some highlighted prices occurred on these days.

Figure 9: Wind generation and forecast, 14-20 July 2024



- 7.3. Figure 10 shows solar generation from 14-20 July 2024. Solar generation exceeded 30MW on Tuesday and Thursday this week, but was otherwise fairly low, particularly on Friday. Solar generation is consistent with shorter days and higher declination angles limiting the availability of the resource during winter.

Figure 5: Solar generation, 14-20 July 2024



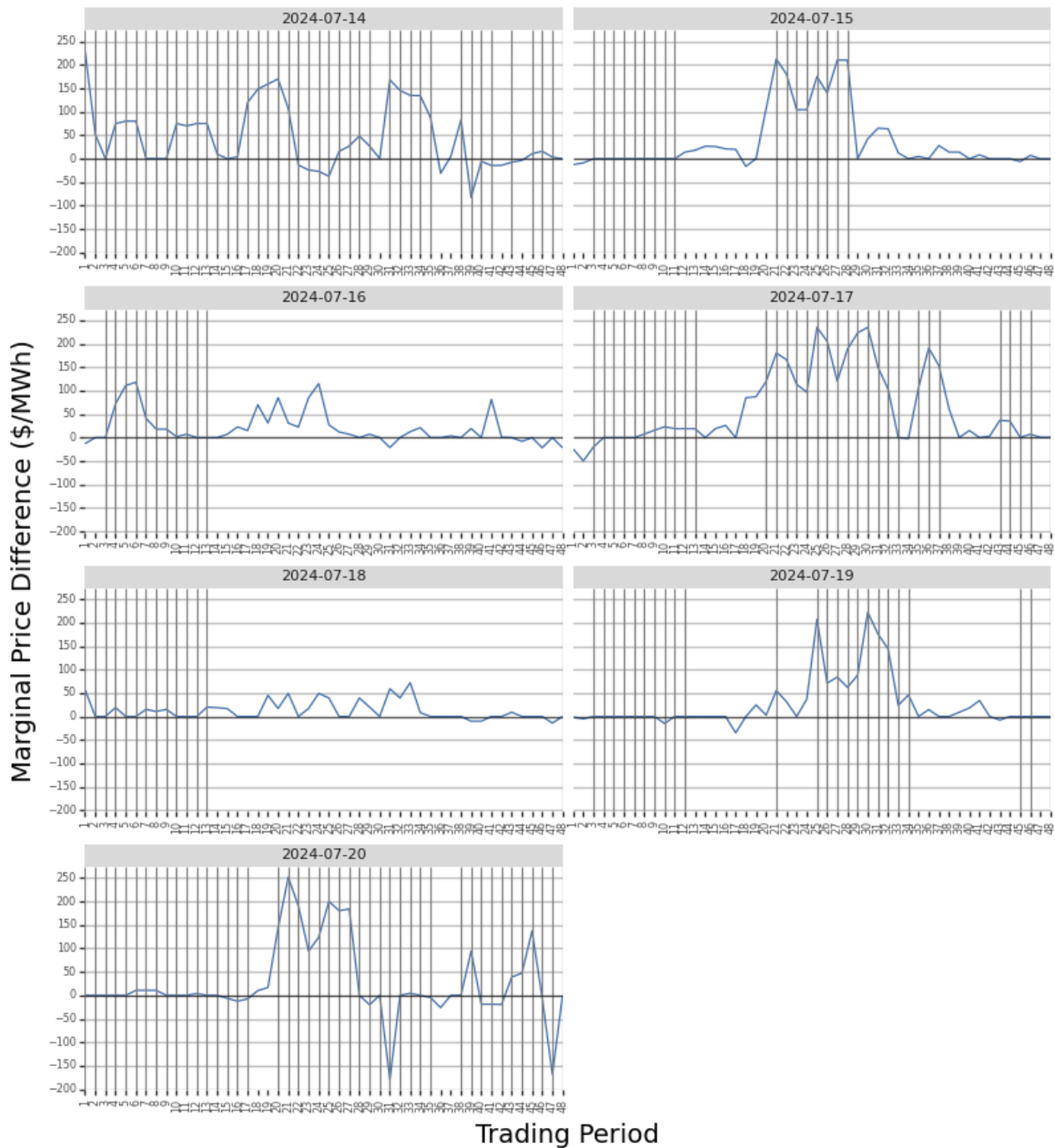
- 7.4. Figure 11 shows the difference between the national real-time dispatch (RTD) marginal price and a simulated marginal price where the real-time wind and demand matched the 1-hour ahead forecast (PRSS²) projections. The figure highlights when forecasting inaccuracies are causing large differences to final prices. When the difference is positive this means that the 1-hour ahead forecasting inaccuracies resulted in the spot price being higher than anticipated - usually here demand is under forecast and/or wind is over forecast. When the difference is negative, the opposite is true. Because of the nature of demand and wind forecasting, the 1-hour ahead and the RTD wind and demand forecasts will rarely be the same. Trading periods where this difference is exceptionally large can

² Price responsive schedule short – short schedules are produced every 30 minutes and produce forecasts for the next 4 hours.

signal that forecasting inaccuracies had a large impact on the final price for that trading period.

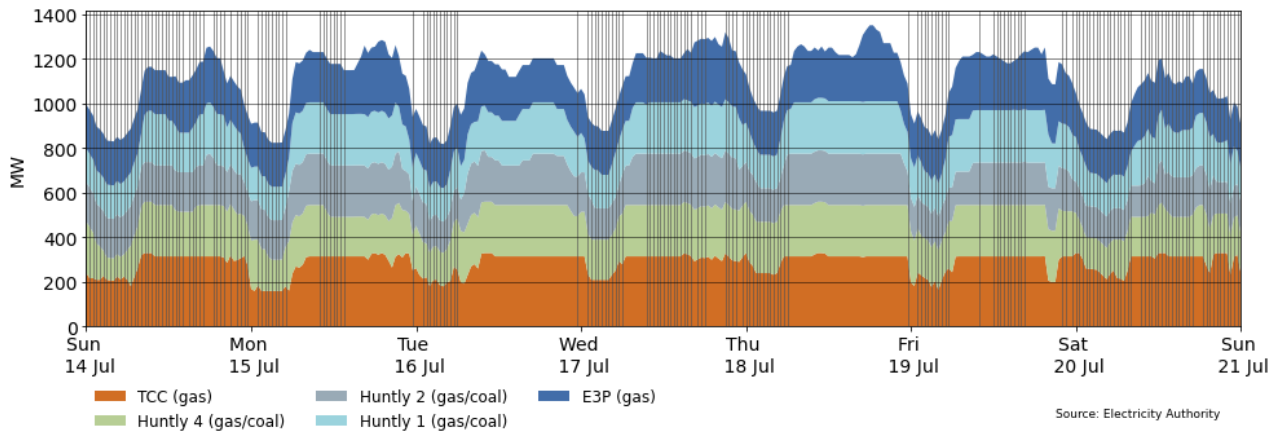
- 7.5. The most notable positive (marginal prices higher than simulation) difference this week was \$252/MWh at 10:00am on Saturday, when demand was higher than forecast. Positive differences exceeding \$200/MWh also occurred on Sunday, Monday, Wednesday and Friday.

Figure 11: Difference between national marginal RTD price and simulated RTD price, with the difference due to one-hour ahead wind and demand forecast inaccuracies, 14-20 July 2024



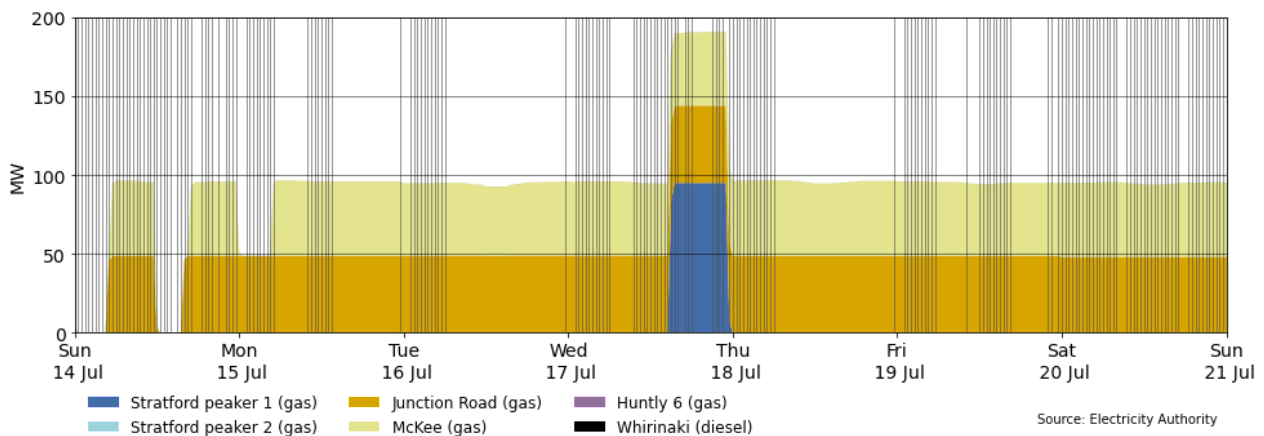
- 7.6. Figure 12 shows the generation of thermal baseload between 14-20 July 2024. TCC, Huntly 4, Huntly 1, Huntly 2 and Huntly 5 (E3P) provided baseload generation this week. All units ran continuously.

Figure 12: Thermal baseload generation, 14-20 July 2024



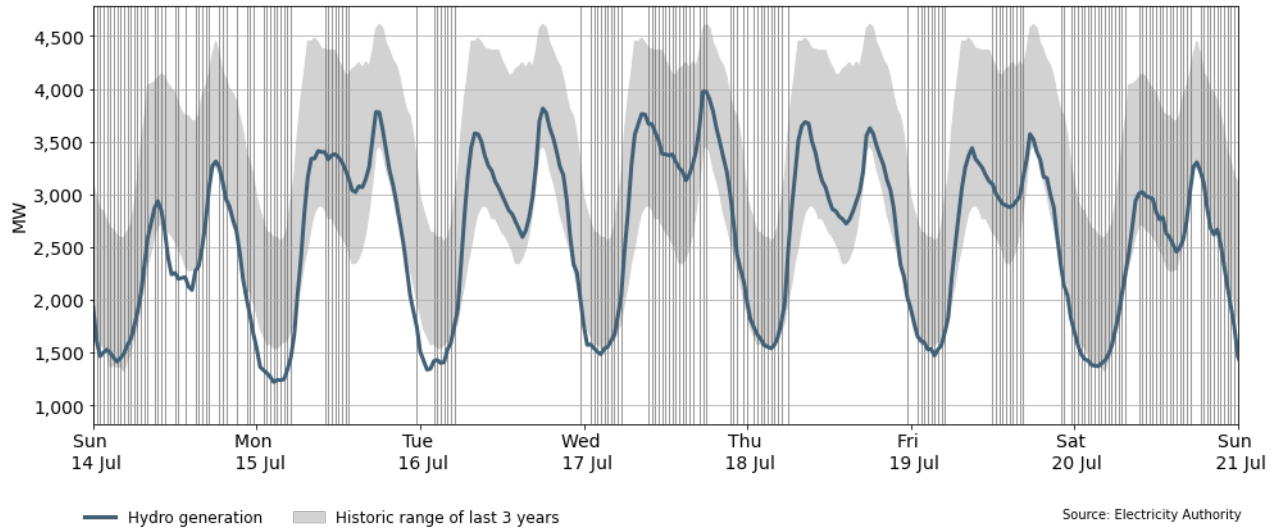
7.7. Figure 13 shows the generation of thermal peaker plants between 14-20 July 2024. Junction Road and McKee both ran one unit (both have a second unit on outage) during peak periods on Sunday, before running continuously as baseload support for the rest of the week. Stratford 1 ran during the evening peak and shoulder period on Wednesday, when wind generation was low and demand was relatively high.

Figure 13: Thermal peaker generation, 14-20 July 2024



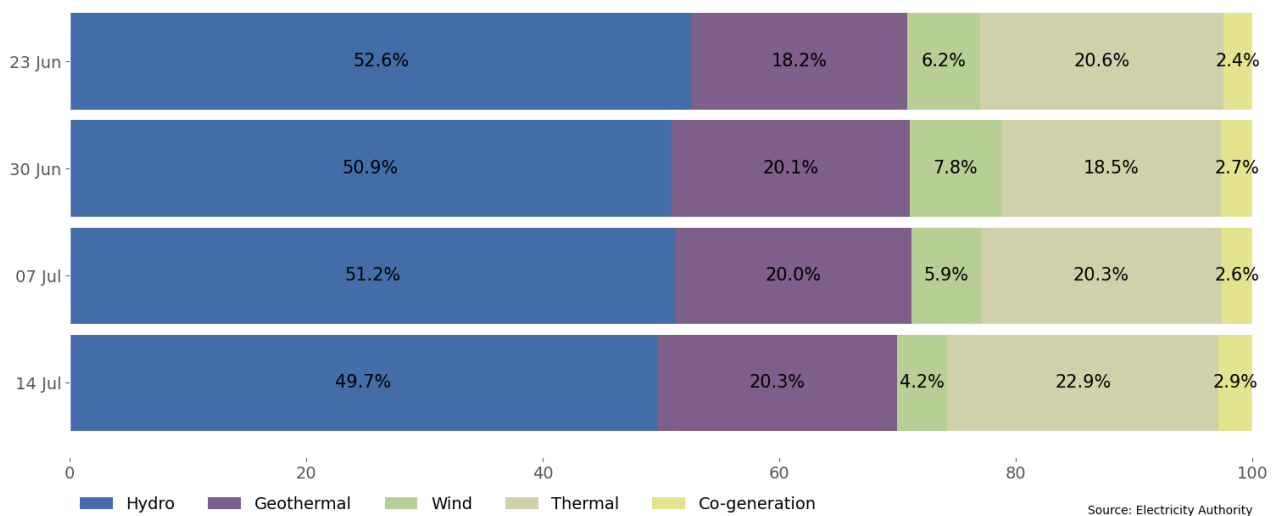
7.8. Figure 14 shows hydro generation between 14-20 July 2024, compared to the historic range of the last three years. Hydro generation was low this week, often close to or below the minimum of the historic range. This is to be expected, as low inflows will lead generators to conserve storage.

Figure 14: Hydro generation, 14-20 July 2024



7.9. As a percentage of total generation, between 14-20 July 2024, total weekly hydro generation was 49.7%, geothermal 20.3%, wind 4.2%, thermal 22.9%, and co-generation 2.9%, as shown in Figure 15. The proportion of thermal generation increased again this week, compensating for the decrease in wind and hydro generation.

Figure 15: Total generation by type as a percentage each week, 9 June-6 July



8. Outages

8.1. Figure 16 shows generation capacity on outage. Total capacity on outage between 14-20 July 2024 ranged between ~730MW and ~1,070MW. Figure 18 shows the thermal generation capacity outages.

8.2. Notable outages include:

- (a) TCC was on partial outage on 19 July.
- (b) Stratford 2 is on outage until 2 September.
- (c) White Hill wind farm is on outage until 16 July.

- (d) Junction Road has one unit on outage until 26 July.
- (e) McKee has one unit on outage, which was originally scheduled to return on 29 July. This outage has now been extended to 29 August.
- (f) Various North and South Island hydro units were on outage.

Figure 6: Total MW loss from generation outages, 14-20 July 2024

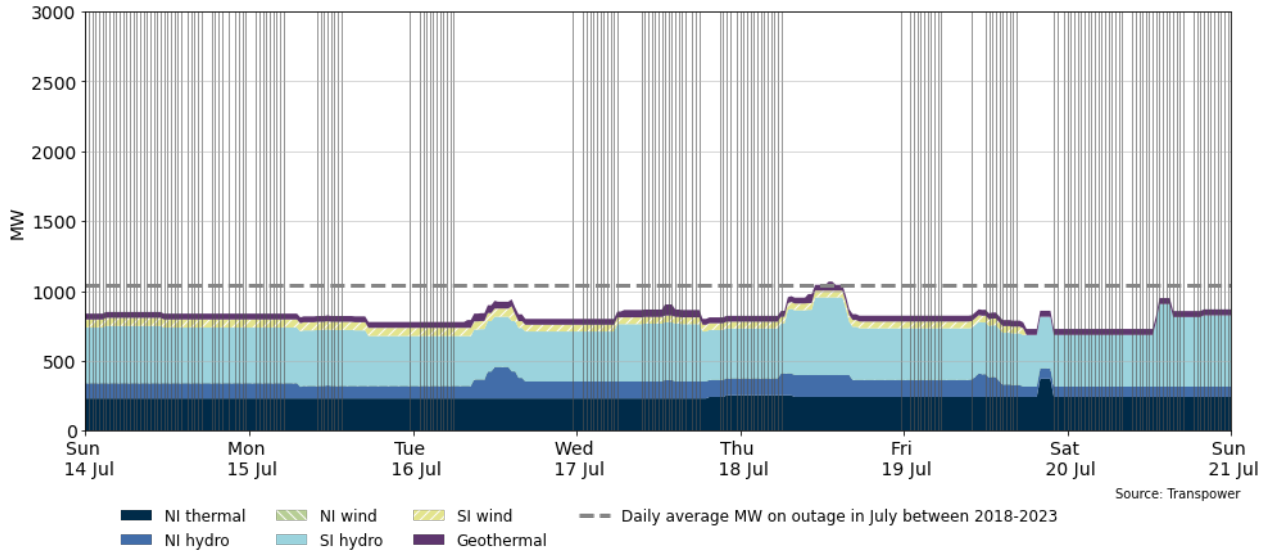
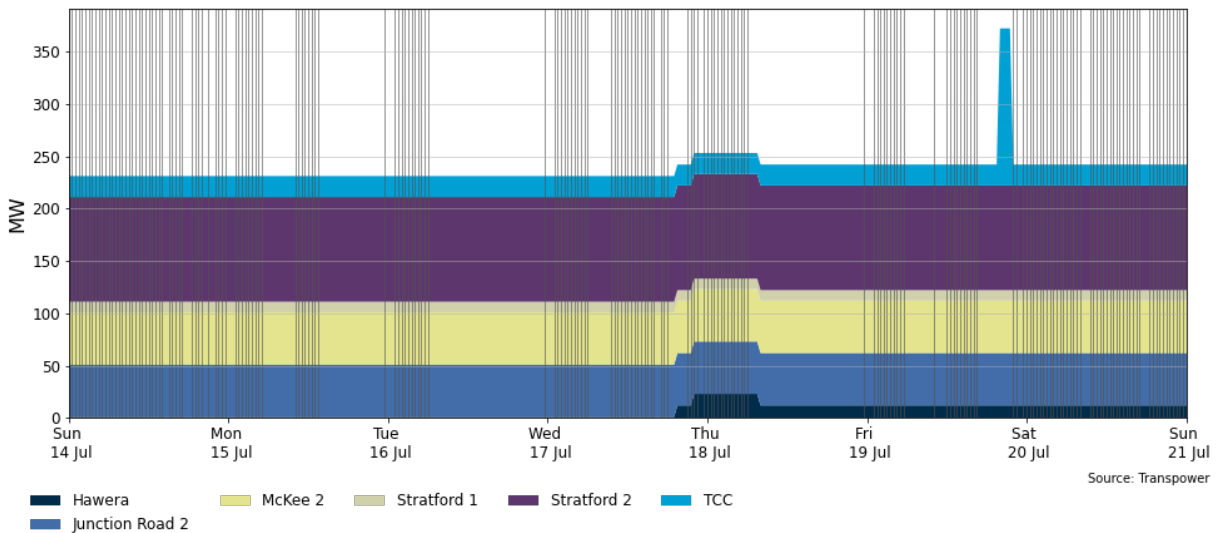


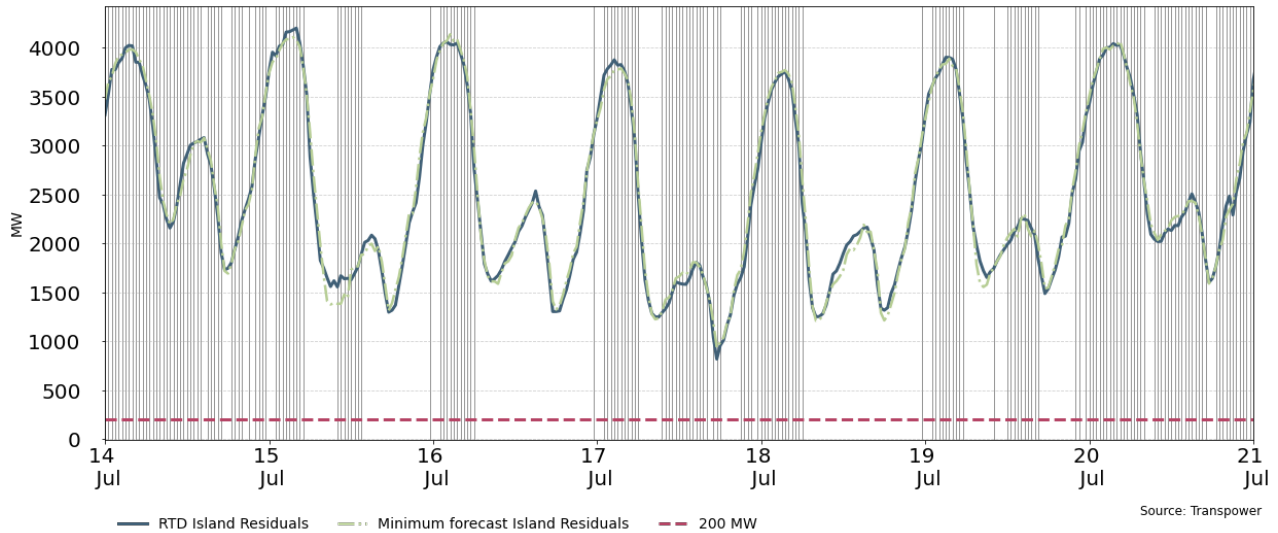
Figure 17: Total MW loss from thermal outages, 14-20 July 2024



9. Generation balance residuals

- 9.1. Figure 18 shows the national generation balance residuals between 14-20 July 2024. A residual is the difference between total energy supply and total energy demand for each trading period. The red dashed line represents the 200MW residual mark which is the threshold at which Transpower issues a customer advice notice (CAN) for a low residual situation. The green dashed line represents the forecast residuals and the blue line represents the real-time dispatch (RTD) residuals.
- 9.2. Generation residuals were healthy this week. The minimum North Island residual was around 408MW at 5:30pm on Wednesday.

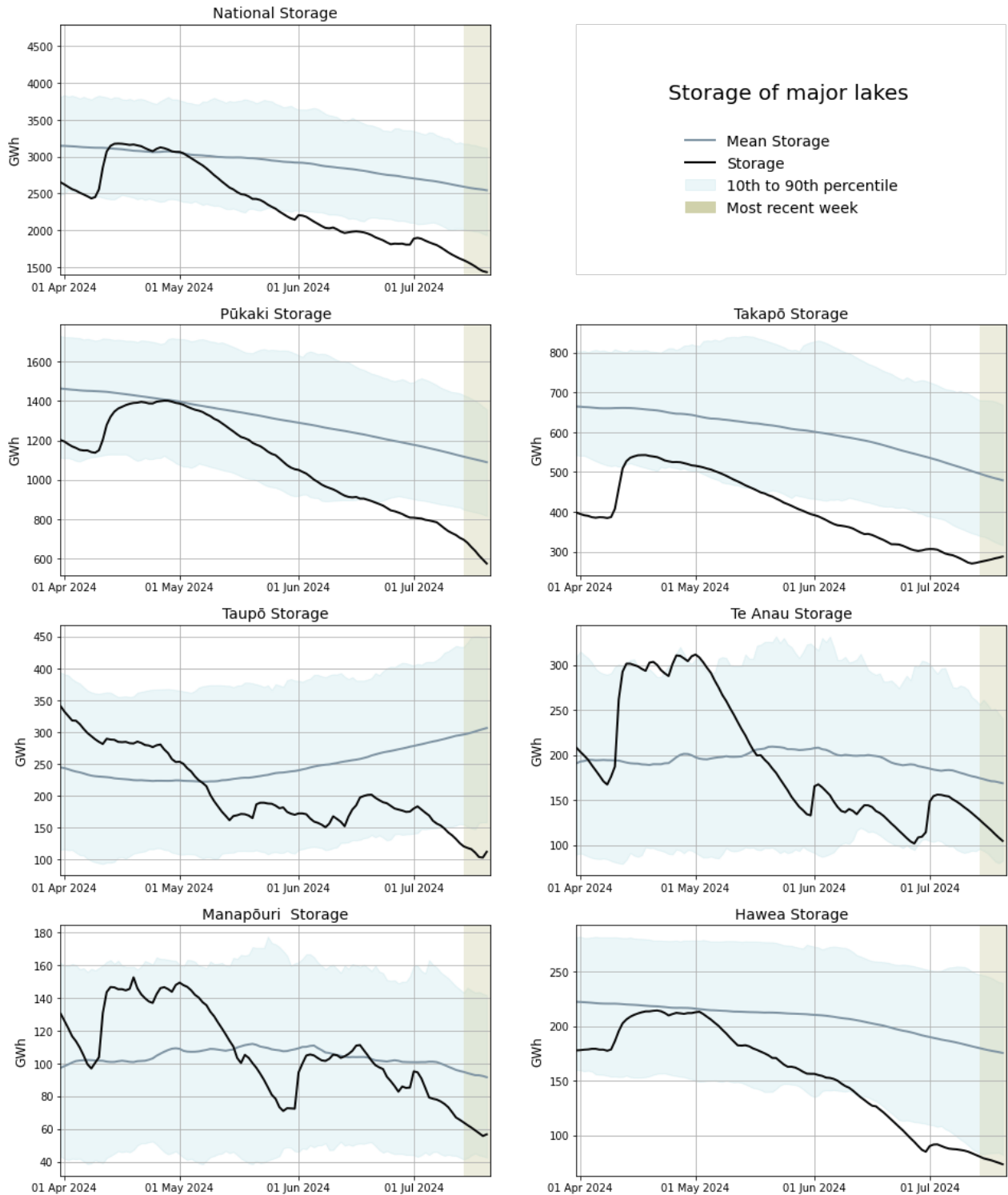
Figure 18: National generation balance residuals, 14-20 July 2024



10. Storage/fuel supply

- 10.1. Figure 19 shows the total controlled national hydro storage as well as the storage of major catchment lakes including their historical mean and 10th to 90th percentiles.
- 10.2. National controlled storage decreased this week and was ~40% nominally full and ~63% of the historical average for this time of the year as of 13 July.
- 10.3. Storage decreased at all major lakes except Takapō, though Taupō and Manapōuri saw a slight uptick at the end of the week. All lakes are below their historical means, with Pūkaki, Takapō, Taupō and Hawea also below their 10th percentiles.

Figure 19: Hydro storage

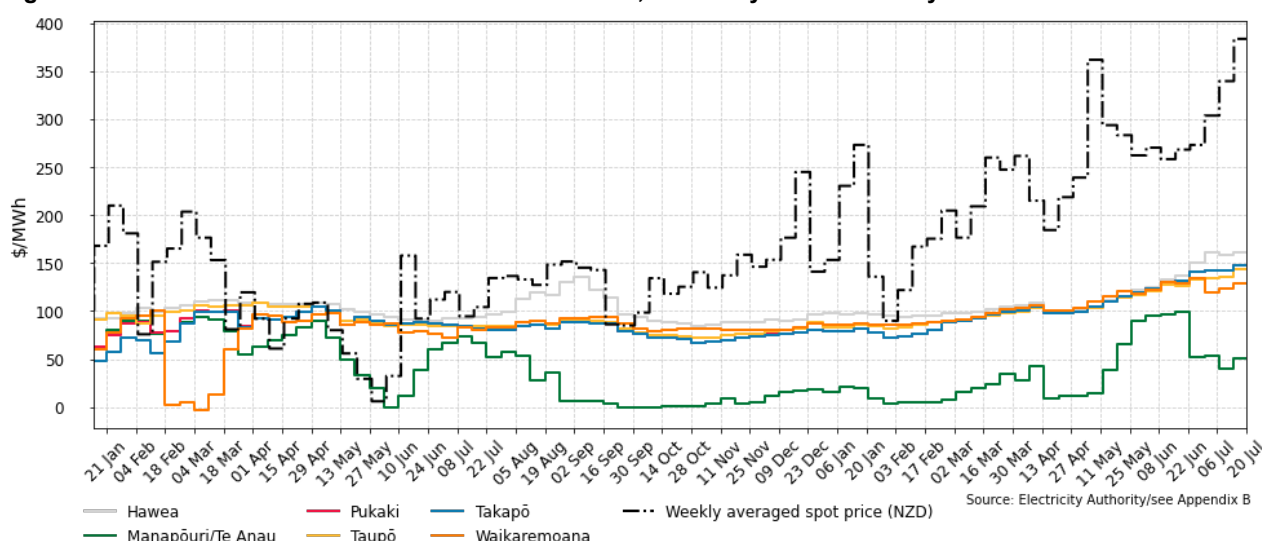


Source: Electricity Authority

11. JADE water values

- 11.1. The JADE³ model gives a consistent measure of the opportunity cost of water, by seeking to minimise the expected fuel cost of thermal generation and the value of lost load and provides an estimate of water values at a range of storage levels. Figure 20 shows the national water values between 1 July 2023 and 13 July 2024 obtained from JADE calculated at the start of the week. These values are used to estimate the marginal water value at the actual storage level. More details on how water values are calculated can be found in [Appendix B](#).
- 11.2. Water values at all major lakes increased compared to the previous week, with Manapōuri/Te Anau seeing the greatest increase of \$11.95/MWh. Water values for Pūkaki, Taupō and Hawea are all at the highest value seen since January 2023.

Figure 20: JADE water values across various reservoirs, 8 January 2023 to 13 July 2024



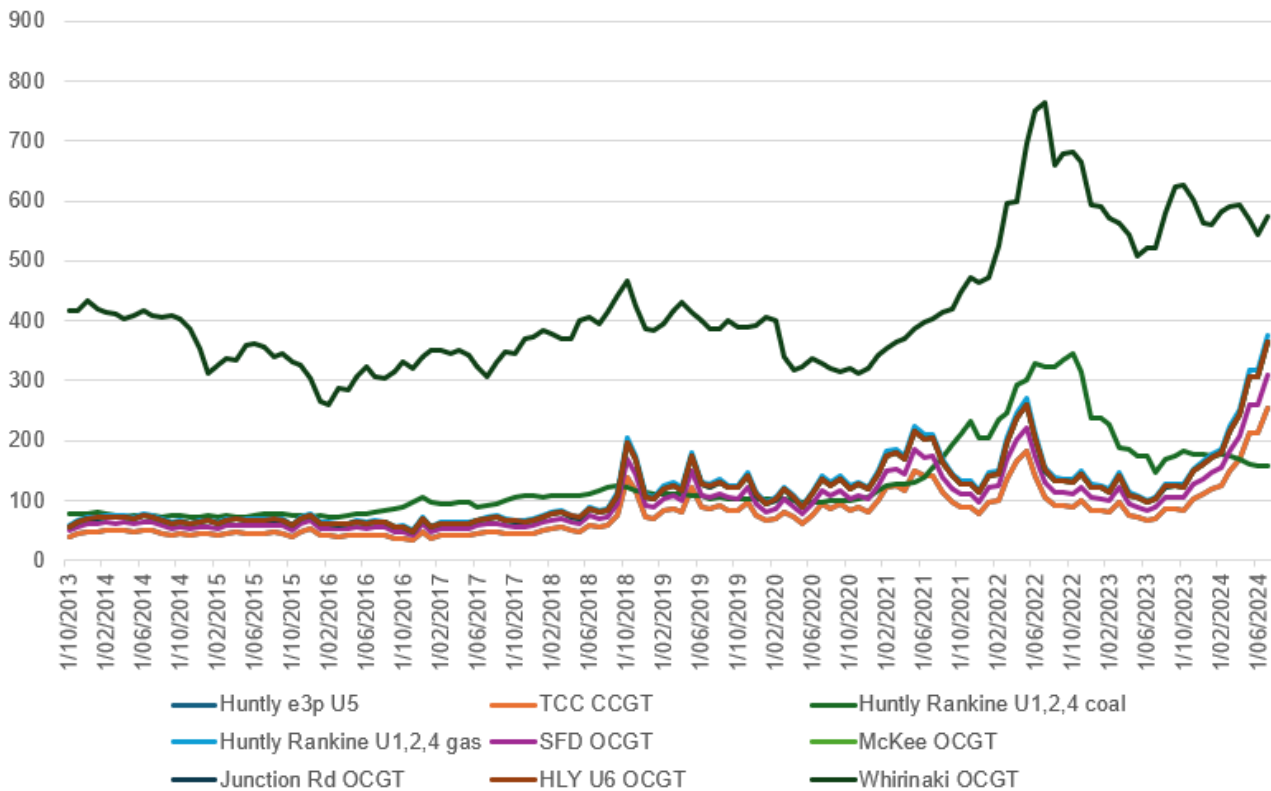
12. Prices versus estimated costs

- 12.1. In a competitive market, prices should be close to (but not necessarily at) the short-run marginal cost (SRMC) of the marginal generator (where SRMC includes opportunity cost).
- 12.2. The SRMC (excluding opportunity cost of storage) for thermal fuels is estimated using gas and coal prices, and the average heat rates for each thermal unit. Note that the SRMC calculations include the carbon price, an estimate of operational and maintenance costs, and transport for coal.
- 12.3. Figure 21 shows an estimate of thermal SRMCs as a monthly average up to 1 July 2024. The SRMCs for diesel and gas have both increased from the previous month, while the coal SRMC has remained stable.
- 12.4. The latest SRMC of coal-fuelled Rankine generation is ~\$158/MWh. The cost of running the Rankines on gas remains more expensive at ~\$377/MWh.

³ JADE (Just Another DOASA Environment) is an implementation of the Stochastic Dual Dynamic Programming (SDDP) algorithm of Pereira and Pinto. JADE was developed by researchers at the Electric Power Optimisation Centre (EPOC) for the New Zealand electricity market.

- 12.5. The SRMC of gas fuelled thermal plants continues to increase and is currently between ~\$254/MWh and ~\$377/MWh.
- 12.6. The SRMC of Whirinaki is ~\$573/MWh.
- 12.7. More information on how the SRMC of thermal plants is calculated can be found in [Appendix C](#).

Figure 21: Estimated monthly SRMC for thermal fuels

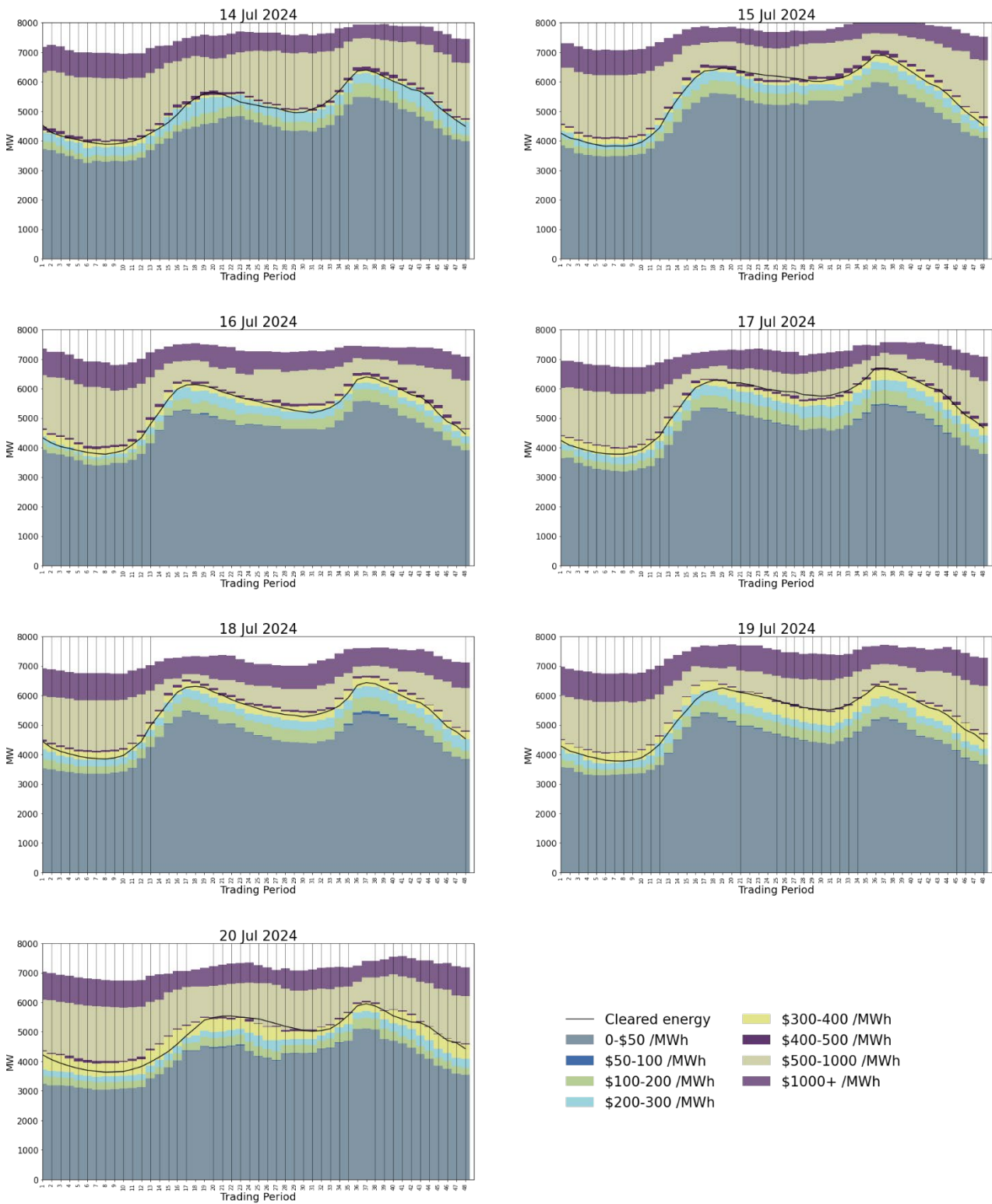


Source: Electricity Authority/see Appendix C

13. Offer behaviour

- 13.1. Figure 22 shows this week's national daily offer stacks. The black line shows cleared energy, indicating the range of the average final price. The number of offers in the \$500-\$1,000 band remains high as a result of low lake levels increasing the price of hydro generation. Although most offers cleared in the \$200-\$400/MWh region, the number of offers in these bands is relatively low. The thin \$400-\$500/MWh offer band led to prices being pushed into the \$600-700/MWh region by under forecast demand on Saturday.

Figure 22: Daily offer stacks



Source: Electricity Authority

14. Ongoing work in trading conduct

14.1. This week, prices generally appeared to be consistent with supply and demand conditions.

14.2. Further analysis is being done on the trading periods in Table 1 as indicated.

Table 1: Trading periods identified for further analysis

Date	Trading period	Status	Participant	Location	Enquiry topic
14/06/2023-15/06/2023	15-17/ 15-19	Passed to Compliance	Genesis	Multiple	High energy prices associated with high energy offers
22/09/2023-30/09/2023	Several	Passed to Compliance	Contact	Multiple	High hydro offers
8/05/2024-10/05/2024	Several	Further analysis	Genesis	Multiple	Energy offers
07/07/2024	11-13	Further analysis	Meridian	South Island	High energy and reserve prices
06/07/2024	41-48	Further analysis	N/A	N/A	Energy offers
13/07/2024	Several	Further analysis	N/A	N/A	High energy prices